Decision ______________________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company in the 2001 Annual Transition Cost Proceeding for the Record Period July 1, 2000, through June 30, 2001.	Application 01-09-003 (Filed September 4, 2001)
Application of San Diego Gas & Electric Company (U 902 E) in the Fourth Annual Transition Cost Proceeding Addressing the Transition Cost Balancing Account (TCBA).	Application 01-09-005 (Filed September 4, 2001)

OPINION GRANTING RELIEF, IN PART

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OPINION GRANTING RELIEF, IN PART

I. Summary

In this Annual Transition Cost Proceeding (ATCP), Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric (SDG&E) seek to recover costs recorded in their Transition Cost Balancing Account (TCBA) from July 1, 2000, through June 30, 2001 for PG&E and from September 1, 2000 through June 30, 2001 for SDG&E.

The decision approves PG&E's request to include in its TCBA $8.9 million of electric supply costs and $415,385 in payments made to employees. It denies PG&E $580,000 in shareholder savings incentive payments. And it finds reasonable $34.8 million of costs associated with the divestiture of PG&E's hydroelectric generation facilities and places that sum in a memorandum account to be allocated at the disposition of the facilities.

It finds that all of SDG&E's entries to its TCBA are reasonable and that its competition transition charge revenue requirement of $115 million should be continued through 2003.

II. Background

The disputed amount for PG&E subject to this proceeding is approximately $44.6 million. The purpose of the ATCP is to ensure that recovery of generation-related costs through the TCBA complies with guidelines established by the Commission. In Decision (D.) 97-06-060 (Phase 1 CTC decision), the Commission, among other things, established the TCBA and the ATCP. Additionally, the Commission identified certain CTC-eligible cost categories and established amortization and depreciation methods for CTC-eligible costs. In D.97-11-074 (Phase 2 CTC decision), the Commission addressed all costs and categories of costs eligible for transition cost recovery. In D.97-12-039, the Commission ordered the utilities to file TCBA tariffs.

In general, the ATCP is the proceeding in which the utility asks the Commission to:

(a) Review entries to must-run and non-must-run memorandum accounts, established in Decision 97-11-074, to ensure that excess revenues are properly credited to the TCBA on an annual basis and that no going forward costs of operating these plants are debited to the TCBA except as allowed by PG&E's tariffs;
(b) Adjust accelerated depreciation and account for results of appraisal applications;
(c) Adjust the TCBA as necessary for capital additions and qualifying facility (QF) contract buy-outs, restructuring, and renegotiations;
(d) Verify ISO and PX costs and revenues; and
(e) Review for reasonableness: (i) employee-related transition costs; (ii) purchased power, QF, and geothermal contract administration; (iii) water purchases; and (iv) mitigation efforts with regard to off-site common and general plant.

Accordingly, PG&E requests that the Commission:

(1) approve the revenues and costs recorded in the TCBA and related memorandum accounts from July 1, 2000 through June 30, 2001, including the 48-month accelerated depreciation of generation assets and scheduled amortization of regulatory assets through the TCBA;
(2) approve recovery of the $10.7 million generation-related workers compensation regulatory asset;
(3) find reasonable $1.7 million in costs associated with water purchases for power;
(4) find reasonable $35.2 million in costs associated with planned divestiture/market valuation activities for PG&E's hydroelectric assets and its Humboldt Bay power plant;

(5) find reasonable PG&E's activities related to QF and other power purchase agreements (PPAs), including the Western Area Power Administration (WAPA) (referred to collectively herein as "must-take generation resources"), and approve recovery of costs (including PG&E's administrative and litigation costs) associated with these contracts;
(6) approve recovery of $0.58 million in QF shareholder incentives related to renegotiated/restructured QF contracts from July 1, 2000 through June 30, 2001;
(7) approve PG&E's must take generation resource bidding and scheduling activities;
(8) approve recovery of $6.5 million in PG&E's electric supply administration costs; and
(9) find that PG&E incurred and recorded employee-related transition costs in accordance with the review provisions of the Commission-approved Settlement Agreement.

The Scoping Memo of the Assigned Commissioner issued November 11, 2001 set forth the issues of the reasonableness of PG&E's generation memorandum account entries and its transition cost balancing account entries. By Administrative Law Judge (ALJ) Ruling the Assigned ALJ added the issue "the reasonableness of PG&E's procurement practices." "Procurement practices" refers to Chapter 1-5 of PG&E's prepared testimony.

ORA filed a motion to bifurcate this proceeding so that the procurement practices issue would be processed on a separate schedule subsequent to the non-procurement practices issues. The motion was granted; the procurement practices issue was separated (as Phase 2) and set for hearing in December 2002. Phase 1 was heard May 13, 2002.

With the exception of four issues, discussed in detail below, and the procurement practices issue, PG&E's request for approval of the revenues and costs recorded in the TCBA and the TCBA-related memorandum accounts from

July 1, 2000 through June 30, 2001, is not in dispute. ORA reviewed PG&E's showing, conducted discovery, and produced a report that either approved or did not dispute a substantial portion of PG&E's request.

III. PG&E

Four issues in Phase 1 of the 2001 ATCP remain unresolved. PG&E and ORA disagree over:

- $8.9 million of electric supply costs, which PG&E asserts are costs to perform its procurement functions;
- $34.8 million of costs associated with the planned divestiture/market valuation of PG&E's hydroelectric generation facilities;[1]
- $580,000 in shareholder savings incentive payments in connection with incremental agreements for energy delivery from QF's during the record period; and
- $415,385 in payments made to bargaining unit employees at divested power plants under PG&E's Bargaining Unit Severance and Displacement (BUSD) program.

Electric Supply Administration Cost

PG&E requests authority to record and recover in the TCBA $8.9 million in electric supply administration costs incurred during the record period. This request reflects $6.2 million in direct costs of activities to perform the procurement function, plus $3.4 million in indirect costs allocated to the electric supply administration business unit using the allocation factors adopted in PG&E's 1999 general rate case (GRC), less a prior period adjustment of $0.7 million.

[1] The Utility Reform Network (TURN) joins ORA in disputing the reasonableness of this cost.

PG&E says that it has recorded electric supply administration costs in the TCBA as a result of the Commission's finding in PG&E's 1999 GRC that these costs are "generation-related." (D.00-02-046, *mimeo.*, p. 110.) Since the advent of the competitive electric marketplace, all of PG&E's generation-related costs have been recorded either in the generation memorandum accounts (GMA) or the TCBA. Given the Commission's determination that these costs are "generation-related," and the fact that electric supply administration costs are not incurred to operate PG&E's generation facilities, PG&E believes the TCBA is the most appropriate place to record the electric supply administration costs.

In the 1999 GRC, the parties litigated the reasonableness of PG&E's revenue requirement forecast for the administrative costs associated with PG&E's procurement of electricity for its customers. The forecast was based on the 1999 Test Year. As a result of that litigation, the Commission adopted a revenue requirement for those activities, which was $10.0 million, and determined that this revenue requirement was not appropriately categorized as a distribution revenue requirement, but more appropriately categorized as generation-related. The result of this determination was that PG&E had to remove this revenue requirement from its distribution revenue requirement and record it in a separate account. While the Commission did not specify in which account those costs should be recorded, PG&E believes that the most appropriate account is the TCBA.

ORA argues that PG&E should not recover any part of its requested $8.9 million in this ATCP. It says that not only is PG&E's request inapposite to the structure and purpose of the ATCP, but it fails on its own merits according to Commission decisions addressing the electric supply procurement expense category. No reasonableness determination should be made and recovery should be denied. Additionally, ORA says that the Commission in PG&E's GRC D.00-02-046 approved direct procurement costs but not indirect costs. Therefore, PG&E must show the reasonableness of $3.4 million in indirect costs.

Finally, and most importantly in ORA's opinion, PG&E's request to recover its electric supply procurement expense in this ATCP is fatally flawed because the expense does not qualify as a transition cost. ORA contends that transition costs are costs that predate deregulation and have, as a result of the competitive generation marketplace, become uneconomic. ORA says that nowhere in the statutory or decisional law (D.95-12-068, D.97-06-060, D.97-11-074) are electric supply procurement costs identified as or determined to be transition costs. As only transition costs are tracked in the TCBA and reviewed for reasonableness in the ATCP, ORA concludes that because electric supply procurement expenses are not transition costs they cannot be recovered in an ATCP.

ORA asserts that regardless of their classification, procurement costs are not suited to resolution in the ATCP. It argues that procurement costs are solely for the benefit of bundled customers, but transition costs are to be recovered through a nonbypassable charge levied on all customers, "whether taking service as full service utility customers . . . procuring their own energy as direct access customers, or departing the utilities' transmission and distribution system altogether. . . ." (D.97-06-060, 72 CPUC 2d 736, 746.) ORA says no transition cost recovery mechanism exists or could exist within the current statutory framework that permits recovery from only bundled service customers and excludes direct access customers. Nonetheless, PG&E persists in its effort to recover non-transition cost procurement expenses through a transition cost proceeding that uses the nonbypassable charge levied on all customers as its recovery device.

We agree with PG&E and will include its electric supply administration costs in this proceeding. As there is no dispute regarding the reasonableness of these costs, we find them to be reasonable. Nor is there any doubt that the revenue requirement for electric supply administration costs authorized in PG&E's 1999 GRC included both direct and indirect costs. (D.00-02-046, Appendix D.) In that decision, our authorized revenue requirement for electric supply administration costs included $7.7 million of forecast direct costs and $2.8 million of indirect costs, a total of $10.5 million. (*Id.* at p. D-1.) D.00-02-046 allocated indirect costs to each unbundled cost category. In doing so, we recognized that it was appropriate that each business unit bear its share of the indirect costs of operating the company. Without incurring such indirect costs PG&E could not perform the direct electric supply administration functions.

ORA's assertion that we should not authorize recovery of these costs because PG&E did not incur the costs on behalf of direct access customers overlooks our findings in D.01-01-019 (Findings of Fact 13 and 14) that direct access customers do benefit from these activities. Finally, ORA's argument that electric supply administration costs are not transition costs and so may not be recovered through the TCBA fails to recognize that we have allowed PG&E to recover non-transition costs through the TCBA. We have authorized PG&E to recover 1) the Workforce Reduction Revenue Mechanism, 2) the generation-related portion of the CEMA, and 3) the costs associated with prior market valuation and divestiture of the PG&E generation assets through the TCBA. (*See* D.01-01-019 and D.00-04-050.)

Costs Associated with the Market Valuation of PG&E's Hydroelectric Generating Facilities

PG&E requests authority to recover $34.8 million in costs associated with the planned divestiture/market valuation of PG&E's hydroelectric generation facilities. Pub. Util. Code § 367(b) requires the Commission to market value the utilities' generation assets not later than December 31, 2001, and directs that the Commission determine the market value "based on appraisal, sale, or other divestiture."

PG&E 's witness testified that the work required to prepare the initial filings and propose a market valuation method to the Commission for the hydroelectric generating facilities was considerable due to the physical location and nature of these facilities. PG&E's hydroelectric system consists of 110 generating units at 68 powerhouses with a total generating capacity of 3,890 megawatts. These facilities span a vast geographic area (the entire northern portion of the state of California) and include 99 reservoirs, 76 diversions, 174 dams, 184 miles of canals, 44 miles of flumes, 135 miles of tunnels, 19 miles of pipe, 5 miles of natural waterways, about 136,000 acres of land owned in fee, generation tie lines, administrative buildings, fleet, materials and supplies inventories, office equipment, and other miscellaneous instrumentation and monitoring support. The system includes 94 contracts for water rights and 163 statements of water diversion and use.

The witness said PG&E's hydroelectric generating facilities were built as integrated utility facilities. As such, the sites contain a mixture of generation, transmission, and distribution assets. Section 367(b) required market valuation of the utilities' generation assets only; therefore, before market valuation could be accomplished, PG&E had to identify and separate the generation assets from the transmission and distribution assets. Additionally, PG&E had to identify permits, easements, and any other encumbrance associated with the hydroelectric generating facilities that might impact a sale or other divestiture. To perform these preliminary activities, PG&E, with assistance from qualified outside counsel and other experts:

- assessed the feasibility of and the technical requirements for separating generation from transmission and distribution assets;
- performed title reviews and land surveys to identify transferable assets;
- determined property subdivision requirements and identification of easements to be created or reserved;
- identified asset record reconciliation and permits that might be transferred or reissued to a potential buyer;
- identified contractual obligations or other liabilities that should be assumed by the potential buyer or retained by PG&E;
- prepared a Phase 1 environmental site assessment;
- verified and inventoried the hydroelectric generating facilities and entered the information into PG&E's Geographical Information System (GIS); and
- prepared title reviews.

PG&E's witness said these preliminary activities cost $11.4 million.

In September, 1999, PG&E filed its application (A.99-09-053) to market value its hydroelectric generating facilities through an auction similar to that used to market value PG&E's fossil and geothermal generating facilities. Approximately 50 parties participated in multiple rounds of written testimony, 35 days of hearings, and filed numerous pleadings in that proceeding. The Commission determined that an analysis under the California Environmental Quality Act (CEQA) was necessary and required the Energy Division to prepare a draft environmental impact report (EIR) in connection with the auction proposal. Additionally, the Commission required PG&E to provide all parties to the proceeding access to detailed information about PG&E's hydroelectric facilities.

PG&E states it incurred $23.2 million to participate in A.99-09-053 and to create and maintain a data room containing all of the information necessary to determine a final market valuation of PG&E's hydroelectric generating facilities. Of that $23.2 million, $10.5 million reflects amounts billed by the environmental consultant that developed the Draft EIR and for Energy Division staff costs. The Energy Division hired this consultant, and directed and managed the CEQA review and development of the Draft EIR. Also associated with the market valuation proceeding and the CEQA process are $7.4 million in costs PG&E incurred to create and maintain a data room. There are financial, engineering, and operations records for PG&E's hydroelectric facilities dating back several decades. In order to ensure thorough collection and disclosure of plant-specific information, and to ensure that bidders and reviewers could have access to this information in a controlled environment, PG&E hired a document services firm, ZIA Information Analysis, to assist with the creation and maintenance of a data room. This is the same firm PG&E retained to assist with the divestiture of its fossil and geothermal assets – resulting in transaction costs similar to those the Commission found reasonable in prior proceedings (*e.g.,* D.01-01-020).

Although the data room was set up to provide bidders, ORA, and Energy Division and their consultants with access to critical plant, operational, financial, and environmental documents, the data room was primarily used by the Energy Division and its consultants for the CEQA review and to respond to discovery. The remaining $5 million spent on the market valuation proceeding and associated CEQA process reflects the cost of outside legal counsel for these activities.[2]

ORA argues that PG&E's costs associated with preparing to market value its hydroelectric generation assets should be disallowed because a) sale of those assets is statutorily prohibited; b) the Commission has not authorized divestiture, and c) the Commission has not given the utility approval to market value the assets using a particular methodology. PG&E's action were thus unreasonable. ORA asserts that PG&E should be disallowed recovery of the entire $34.8 million, with the exception of $6.4 million incurred in response to a CEQA invoice from the Commission. ORA recommends a disallowance of $28.4 million.

ORA says the divestiture/market valuation cost aspect of PG&E's application is premature and unduly speculative. It believes PG&E is asking the Commission to make a reasonableness determination based on a deficient and incomplete record. The money spent thus far was, in theory, spent in the course of a process which is far from over, and arguably has not even begun. The Commission has not yet approved of a particular market valuation method, and divestiture of hydroelectric facilities cannot occur until 2006 at the earliest under Assembly Bill (AB) AB1X-6; (Pub. Util. Code § 377).

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[2] The total request of $34.8 million included $.5 million of miscellaneous expenses. The breakdown is:

$11.4 – preliminary activities
10.5 – CEQA
2.4 – Data Room
5.0 – Lawyer
.5 – Misc.
$34.8 Total

(*See*, Ex. 1, Chapter 5, p. 5-17.)

ORA asserts that on this record we cannot determine whether the $28.4 million was reasonably spent because the outcome of the process is still unknown. Since the divestiture process is so highly speculative, ORA contends that PG&E should bear the burden of an unsuccessful auction or spinoff. If significant ratepayer savings are not ultimately achieved, there will be a legitimate question of whether the millions spent in preparing for that auction was reasonable. However, ORA states that this question cannot be answered at present.

If the Commission will not disallow the expenses at this time, then ORA recommends delaying this reasonableness review in order to provide PG&E with an incentive to maximize ratepayer savings in whatever valuation or divestiture eventually takes place. That motivation will be entirely absent should PG&E be permitted to recover a large portion of expenses before the process itself has been completed. ORA contends that granting PG&E recovery at this juncture is a guarantee to the utility's shareholders that they will bear no responsibility should the eventual outcome – whether an auction or otherwise – fail to produce successful results and net benefits to customers.

The prospect of a double recovery by PG&E of the $28.4 million also argues in favor of deferring a reasonableness review until the valuation and/or divestiture process has run its course, in ORA's opinion. For example, review of title to land acquired over the last 100 years, as well as land surveys, were a major part of the activities funded by the $28.4 million. The net effect of clearing title and conducting surveys of the land will be to enhance the value of any given asset, which will be reflected in the sales price should divestiture ever occur. If PG&E is able to recover the capital expenditures now in rates, the prospect of double recovery when divestiture – whether via a bankruptcy reorganization plan or not – takes place is quite likely.

Another consideration, says ORA, is that the eventual buyer of the hydro assets will pay for the transaction costs incurred to prepare for the sale, as happened in the divestiture of PG&E's fossil plants. As PG&E explained, "[t]he transaction costs were netted from the proceeds, and . . . went to offset transition costs, which is what Section 367(b) was intended to do." (PG&E/Montana, RT 145.) It would not make sense to book the $28.4 million transaction costs to the TCBA and permit recovery before the price for the asset has been established.

ORA believes that PG&E acted in a complete absence of Commission authority. Pub. Util. Code § 367(b) dictates that uneconomic, or stranded, costs attributable to generation-related assets such as hydroelectric plants shall in part be calculated "based on appraisal, sale, or other divestiture." The Public Utilities Code gives the Commission the exclusive authority to determine which of the valuation methods will be used. ORA concludes that the expenditures by PG&E to value its hydroelectric resources had to be spent the way the Commission directed it be spent. But that never happened. The Commission never selected a valuation methodology for PG&E to use. PG&E was acting in a regulatory vacuum when it spent the $28.4 million dollars. Moreover, D.97-11-074 made it clear that a formal proceeding would be required "to establish the principles necessary to appraise [the utilities'] retained assets and to report assessments of the materials and supplies inventories. . . ." (D.97-11-074, Ordering Paragraph 17.)

ORA points out that at various times PG&E expected to market value its hydro generation by an auction, by a sale, and by appraisal. PG&E, today, does not know how the valuation will be achieved. As a result, ORA declares, at the bottom line, PG&E spent more than $28.4 million without a clear view of exactly what purpose it was to achieve. In ORA's opinion, that sort of behavior is unreasonable – if not irresponsible – under any objective standard. Therefore, the costs incurred thus far in the market valuation/divestiture efforts should be disallowed.

Finally, ORA argues that PG&E has not met its burden of proving reasonableness. It says that even if PG&E is permitted to pursue recovery of money spent in pursuit of a nonexistent target, PG&E's proof of reasonableness is inadequate. The most glaring example, according to ORA, is that when proposing to pursue an auction at one point, and an appraisal at another point, PG&E did not evaluate the relative fiscal impacts of each process. ORA refers us to PG&E's witness' statement that PG&E did not do a detailed analysis of how much it would cost ratepayers depending on which valuation method was chosen. (RT 61-62.) Nonetheless, $28.4 million was spent preparing for both appraisal and auction.

ORA's disallowance argument is not persuasive. It contradicts its own position in prior proceedings and ignores Commission decisions which approved of similar costs. ORA argues that we must disallow all costs because we had not given the utility approval to market value the assets using a particular methodology. However, we must acknowledge the language of Pub. Util. Code § 367(b) that was operative at that time,[3] the time required to process

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[3] "The Commission shall identify and determine those costs . . . of generation facilities. . . . " the valuation of those facilities "shall be determined not later than December 31, 2001, and shall be based on appraisal, sale, or other divestiture." (Pub. Util. Code § 367(b).) In D.01-10-067, the Commission has recognized the impact of AB6X on various Pub. Util. Code sections. The requirement to market value assets

Footnote continued on next page

proceedings at the Commission, the physical nature of PG&E's hydroelectric generating facilities, and the legislative and regulatory conditions at the time PG&E undertook the activities necessary to accomplish market valuation and to participate in market valuation proceedings. Clearly, we cannot ignore those items.

Prior to AB6X, it was the Commission's obligation to market value the utilities' generation assets. We could not have performed this task without obtaining detailed information about those assets from the utilities, and input from ORA and other interested parties about how the market valuation should be performed. A review of PG&E's response to § 367(b) is instructive. For its fossil and geothermal generating facilities, PG&E provided the Commission with detailed information through applications pursuant to Pub. Util. Code § 851 proposing to market value those assets through an auction process resulting in a sale to the highest bidder. (*See*, A.96-11-020.)

To obtain utility, ORA, and other interested parties' input into the appropriate method to market value the utilities' generating assets, we directed the utilities to indicate whether they intended to retain any generating facilities and to file appraisal principles for retained generation by May 1, 1998. (D.98-04-065, *mimeo.,* Ordering Paragraph 2.) In its May 1, 1998 filing, PG&E stated that it did not intend to retain any non-nuclear generating facilities, but suggested that appraisal might be an appropriate method for determining the

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which must now be retained is being considered in A.00-11-038 et al. (*See* Assigned Commissioner's Ruling of President Lynch, issued on December 21, 2001.) Furthermore, the Commission has determined that stranded assets no longer exist, within the meaning of AB 1890. (*See* D.02-11-026 and the discussion of the return to cost-of-service ratemaking vis-a-vis ABX 1-6.)

market value of PG&E's hydroelectric generating facilities. (A.98-05-022.) ORA and other parties objected to appraisal as the market valuation proposal. PG&E revised its proposal and filed an application under Pub. Util. Code § 851 to market value the hydroelectric generating facilities through an auction. (A.99-09-053.)

In that proceeding, approximately 50 parties participated in multiple rounds of written testimony, 35 days of hearings, and filed numerous pleadings. PG&E responded to 90 sets of data requests addressing environmental issues alone and to over 50 data requests on other issues. The Assigned Commissioner determined an analysis under CEQA was necessary and required the Energy Division to prepare a draft EIR.[4] Additionally, the Assigned Commissioner required PG&E to provide all parties to the proceeding access to the detailed information about PG&E's hydroelectric facilities to be housed in a data room.[5]

We have no doubt that the previously-operative December 31, 2001 deadline set by Pub. Util. Code § 367(b) and the nature of PG&E's hydroelectric generating facilities required that PG&E undertake the activities necessary for market valuation in advance of a final Commission determination of the method for market valuation. In the past, ORA apparently agreed with that procedure. In early January 1999, ORA asked the Commission to direct the utilities to begin their auction processes immediately. Specifically, ORA stated:

> The effort that the utilities propose to enter into as part of their proposed appraisal proposals – creation of data

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[4] *See Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge,* A.99-09-053, January 13, 2000.

[5] *See Ruling of Assigned Commissioner and Administrative Law Judge Regarding Access to Information, A*.99-09-053, February 2, 2000.

> rooms, provision of all information needed for due diligence investigations – appears to be very similar to the actions a utility would go through for an auction. Why not get ready for an auction now?[6]

And, of course, we agreed with ORA. In D.00-03-019, we ordered PG&E "to file applications valuing remaining generation and generation-related assets, a supporting methodology, and proposed ratemaking treatment, to establish a final valuation pursuant to § 216(h), 367(b), and 377." (D.00-03-019, p.2.)

PG&E did get ready for an auction of its hydro properties; it created a data room and provided information so that prospective bidders could do their due diligence work. It is too late for ORA to complain that PG&E should have waited for an order of the Commission authorizing an auction, or any particular method of valuation.

Although ORA challenged PG&E's transaction cost of $34.8 million as being unreasonably high, ORA presented no evidence to substantiate its challenge. Nevertheless, whether or not there is a challenge, PG&E has the burden to show that its transaction costs are reasonable.[7] We believe it has.

For example, ORA asserts that PG&E should have chosen the least expensive law firm and other outside vendors regardless their experience or level of expertise. It disputes PG&E's retention of O'Melveny and Myers and ZIA Information Analysis Group based on PG&E's failure to demonstrate whether these were the least expensive options available to PG&E. In focusing

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[6] Second Prehearing conference statement of ORA dated January 8, 1999 in A.98-05-022; Exhibit 7, VIII, p. 13.

[7] TURN makes the same argument.

solely on "least cost," ORA disregards the reason why those firms were a reasonable choice to assist PG&E with the hydroelectric generating facilities - they had the experience and expertise to do the job. Those firms had been approved by ORA in its review of PG&E's divestiture of its fossil and geothermal facilities in PG&E's 1999 ATCP. By retaining those firms again, PG&E captured the expertise they acquired from assisting in the prior divestiture/market valuation proceeding. Moreover, despite the fact that PG&E's hydroelectric generating facilities are far more complex than PG&E's fossil and geothermal generating facilities, the difference between the transaction costs PG&E incurred in connection with the hydroelectric generating facilities and the fossil and geothermal generating facilities reflects only the costs of the Commission's CEQA consultant. (*See* D.97-12-107 and D.99-04-026.)

We find that PG&E's transition cost expense of $34.8 million is reasonable. It represents the cost of preparing for sale, appraisal, or divestiture properties which include 110 generating units, 99 reservoirs, 174 dams, 184 miles of canals, 44 miles of flumes, 19 miles of pipe, 5 miles of natural waterways, and about 136,000 acres of land owned in fee. Properties which, on more than one occasion, ORA has valued at more than $1.6 billion. (*See* for example, A.98-05-022, Response of ORA, 11/3/98, p. 1, ". . . the amount of money involved is huge – billions of dollars worth of plant are involved."; Second Prehearing Conference Statement of ORA, 1/8/99, p. 1, "PG&E's hydro system alone has a book value of $1.6 billion and it is generally believed to have a market value substantially higher than that.") In the valuation of PG&E's Moss Landing and Oakland fossil fuel plants we found that the transaction expense of $9.9 million was reasonable in relation to a $501 million sale; a 2% expense ratio. (78 CPUC 2d 164 at 170.) An expense of $34.8 million, which includes a CEQA expense of $6.4 million, cannot be considered unreasonable in a $1.6 billion-plus expected sale, appraisal, or divestiture; a 2% expense ratio.

Our inquiry does not end with a finding of reasonableness. We must also determine whether these transaction costs should be debited to the TCBA and recovered from ratepayers. We believe it would be premature to do so. AB 1890 established a scheme to transition the California electricity generation market to competition by March 31, 2002, with the expectation that generation-related assets would be market valued by December 31, 2001. In that context, § 367(b) states that for those generation-related assets that the Commission determines to be transition costs and that are subject to valuation, "the valuation used for the calculation of the uneconomic portion of the net book value shall be determined not later than December 31, 2001, and shall be based on appraisal, sale, or other divestiture."

On January 18, 2001, Governor Davis signed ABX1 6. This statute fundamentally changed many of the principles embedded in AB 1890 regarding the regulation and divestiture of generation assets owned by the utilities. For example, ABX1 6 amends § 377 to explicitly delete any reference to market valuation and instead states that the Commission's regulatory authority continues" until the owner of those facilities has applied to the Commission for disposal of the facilities and has been authorized by the Commission under § 851 to undertake that disposal."[8] Section 377 now requires that "no facility for the generation of electricity owned by a public utility may be disposed of prior to

[8] We note that we have always retained the requirement that utilities must seek authority under § 851 to dispose of or otherwise market value their assets. (*See, e.g.,* D.00-01-024, 2000 Cal-PUC Lexis 4 at 4.)

January 1, 2006." In addition, the Commission must "ensure that public utility generation assets remain dedicated to service for the benefit of California ratepayers."

ABX1 6 also modified § 330(l)(2). Pursuant to AB 11890, § 330(l)(2) originally read, as follows:

> Generation of electricity should be open to competition <u>and utility generation should be transitioned from regulated status to unregulated status through means of commission-approved market valuation mechanisms</u>. (Emphasis added.)

AB6X removed the underlined language; thus, it is clear that the Legislature unambiguously stated that utility retained generation assets should remain regulated and that market valuation mechanisms were no longer required. (We also discuss this in D.02-11-026, *mimeo.*, at pp. 11-14.)

Our concern is that under certain circumstances PG&E could, in effect, obtain a double recovery of the transition costs. Our accounting treatment of the sale of other PG&E generating stations illustrates the point. In D.97-12-107 (A.96-11-020), we approved the sale of PG&E's Moss Landing and Oakland fossil fuel plants. In regard to the TCBA, we said "Because the sales proceeds exceed the net book value, the difference between the book value of the plants and sale proceeds, net of transaction costs and tax effect, will be credited to the Transition Cost Balancing Account (TCBA)." (78 CPUC 2d 164 at 170.)

In the conventional sale of a generating plant the transaction costs are recovered from the sales price and the profit (if any) is credited to the TCBA. There is no question of a double recovery of costs. In the case of the hydro transaction costs, if they are debited to the TCBA, PG&E would recover them in rates today, but given the language of AB6X, divestiture of the hydro facilities could occur, years later, in a manner where the ratepayers would not receive credit for the value above book. To avoid this unfair result, we will hold the transaction costs in a memorandum account to be allocated at the disposition of the hydro facilities, which will not occur prior to 2006. Should the hydro facilities remain with PG&E after 2006, we will entertain a petition to dispose of the memorandum account.

Shareholder Savings Incentive

In order to bring additional energy to the marketplace during the record period, PG&E negotiated amendments to 15 existing power purchase agreements with QFs that could generate energy in addition to the amount delivered under the existing power purchase agreement. PG&E paid for this energy at negotiated rates that were specific to each QF. PG&E asserts that the purchase price for power negotiated in each of these agreements was lower than the price PG&E would have paid for the same power if it had purchased the power from the PX.

PG&E requests authority to recover in the TCBA the cost of 29 incremental energy agreements in the TCBA. Additionally, PG&E requests a 10% shareholder savings incentive ($580,000) in connection with 15 of the 29 agreements. PG&E argues that its request should be approved because these voluntarily-negotiated modifications to existing QF contracts: (1) provided additional revenues to offset costs in the TCBA and (2) increased the amount of energy available in the marketplace.

As support for its position, PG&E cites D.95-12-063 where the Commission allowed shareholders to retain 10% of the net ratepayer benefits resulting from renegotiation of existing QF power purchase agreements relative to the most probable stream of payments for that QF without the modification.

The Commission expected such renegotiations to provide ratepayer benefits by reducing the QF obligation to deliver energy to the utility at the price agreed to in the existing power purchase agreement. PG&E notes that while the incremental energy agreements in this proceeding increase rather than reduce the QF obligation to delivery energy to the utility, these incremental energy agreements save the ratepayers money and enlarge ratepayer benefits by making an additional source of energy available to the marketplace, reducing PG&E's power purchase costs.

ORA agrees that it was reasonable for PG&E to enter into these agreements and recommends that the Commission allow PG&E to recover the costs of these agreements in the TCBA. However, ORA recommends that the Commission reject PG&E's request for $580,000 in shareholder savings incentives because PG&E lacks legal authority for recovery of shareholder incentives. ORA argues that D.95-12-063 permits shareholder incentives related to QF-utility contracts under distinctly different circumstances than those presented here. D.95-12-063 referred to utilities and QFs renegotiating existing contracts after deregulation, the utilities in order to reflect Power Exchange (PX) – based prices in the short-run avoided cost calculations for QF energy payments; the QFs in order to compete in a deregulated market. (64 Cal.P.U.C.2d 1, 64.) As a result, the Commission approved a sharing of utility cost savings between ratepayers and shareholders as an incentive to utilities to renegotiate QF contracts on more favorable terms, with the goals of "reducing transition costs and releasing QFs from contract obligations to allow them to compete in the generation market." (*Id.* at 64-65.)

ORA points out that the incremental energy agreements at issue in this proceeding accomplish neither objective; the agreements actually increase QF obligations and cost the utilities more. PG&E's argument that the incremental energy agreements reduce transition costs by being cheaper than if power had been purchased through the PX is misleading, in ORA's opinion. During the record period, PX power costs experienced unprecedented inflation as megawatt prices sold into the exchange dramatically increased. Any QF power, whether purchased under original or renegotiated contracts, was almost inevitably less expensive than PX power. Given that the QFs benefited from these renegotiations, it is ORA's opinion that those contracts would have been renegotiated with or without the prospect of a 10% shareholder retention of benefits. The utility and its shareholders should not be rewarded, and ratepayers penalized, for taking the only sensible course of action in the face of the energy crisis.

ORA's position is correct. There is no doubt that PG&E acted prudently in renegotiating these QF contracts. But we would expect prudent behavior on the part of PG&E, and especially at a time when the electric market was dysfunctional. Prudency is the norm; it is not exceptional conduct to be rewarded without prior Commission approval. From the beginning of rate regulation prudent conduct on the part of management has been expected. In discussing the adequacy of utility earnings, the Supreme Court held that a return "should be adequate, under efficient and economical management. . . ." (Bluefield Water v. West Virginia PSC (1923) 262 US 679, 693, 67 L. Ed 1176, 1183 (emphasis added).) The Pub. Util. Code requires PG&E to "furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment, and facilities . . . ." (Pub. Util. Code § 451.) PG&E has an obligation to prudently manage its electric contracts. (Cf. Re PG&E 3 CPUC 2d 552, 563; "PG&E's obligation to prudently manage its gas supply resources.") Pub. Util.

Code § 456[9] supports our result. The sentence "the commission may make or permit such arrangement with any public utility as it deems wise for the purpose of encouraging economies, efficiencies, or improvements and securing to the public utility making them such portion of the profits thereof as the commission determines" is particularly relevant. To make a reward arrangement "for the purpose of encouraging economies" presupposes a Commission order authorizing a reward before the economies are instituted. This was done in D.95-12-063 (64 CPUC 2d 1, 64-65.)

Although the contracts in this proceeding are QF contracts as were the contracts in D.95-12-063, that is the only similarity. As ORA points out, in D.95-12-063, the Commission was dealing with a situation where the utilities would want to minimize payments of above market costs and the QFs would want to reduce obligations in order to reflect PX pricing. The fundamental shift in the electric market between 1995 and today has turned those QF contracts topsy-turvy. The current renegotiation, rather than lowering power costs, increased them; and rather than reducing QF obligations, increased them. PG&E acted prudently, but is not entitled to a reward.

Employee-Related Transition Costs

In order to retain skilled workers at divested power plants affected by electric industry restructuring, the Legislature directed the Commission to allow

[9] Section 456 reads as follows: Nothing in this part shall be construed to prohibit any public utility from profiting, to the extent permitted by the commission, from any economies, efficiencies, or improvements which it may make, and from distributing by way of dividends, or otherwise disposing of, such profits. The commission may make or permit such arrangement with any public utility as it deems wise for the purpose of encouraging economies, efficiencies, or improvements and securing to the public utility making them such portion of the profits thereof as the commission determines.

recovery of reasonable employee-related transition costs incurred and projected for severance, retraining, early retirement, outplacement, and related expenses. (Pub. Util. Code § 375.) In D.00-02-048, we adopted a settlement in which PG&E, the Coalition of California Utility Employees, and ORA agreed to the terms of PG&E's employee-related transition programs and narrowed the scope of review of PG&E's expenditures under these programs to a review of whether: 1) PG&E incurred costs only for employees eligible to receive benefits under the specific terms of these programs; 2) PG&E appropriately identified the costs of these programs; 3) PG&E accurately recorded the costs associated with these programs to the TCBA; and 4) PG&E's costs do not exceed the caps adopted in the Settlement Agreement.

PG&E incurred approximately $21.5 million in payments for its Bargaining Unit Severance and Displacement (BUSD) program during the record period. ORA recommends a disallowance of $415,385 associated with payments to eight employees through this program. These employees, who were each displaced from one of PG&E's divested power plants and subsequently placed into a position at another power plant that was divested, received more than one final $50,000 payment under the terms of the BUSD program.

ORA asserts that any payments to employees after they had received a final payment as a result of displacement from one divested plant are "duplicate" excessive payments and should not be recoverable through the TCBA. PG&E maintains that it has appropriately applied the payment provisions of the BUSD program and that it has made no "duplicate" or excessive payments to employees. PG&E contends that all of the BUSD payments were made as a result of two separate and distinct displacements.

Under the BUSD program, in addition to their existing severance benefits, employees may receive payments after Commission approval of a Pub. Util. Code § 851 application for plant divestiture. Specifically, employees remaining at a facility after approval of the plant divestiture receive up to a $50,000 final payment when displaced or laid off. An employee receives the $50,000 final payment at the time of displacement and in conjunction with the demotion and layoff provisions of the appropriate collective bargaining agreement.

These eight employees were eligible for the first $50,000 final payment they received under the BUSD program in connection with their displacement from the first divested power plant because: 1) they were regular employees whose positions at divested power plants were required by the Operations & Maintenance (O&M) agreement; 2) their positions were eliminated; and 3) they received displacement notices under the provisions of the collective bargaining agreement. PG&E asserts that each of these eight employees was eligible for additional benefits under the BUSD program because, after being displaced from the first divested power plant: 1) they were placed as regular employees into positions at a second divested power plant that were required by the O&M agreement for that divested power plant; 2) their positions were eliminated, and 3) they received displacement notices under the provisions of the collective bargaining agreement.

ORA's recommended disallowance is based on the fact that payments under the BUSD program beyond a single, final, $50,000 violate the unambiguous statutory directive that the entire purpose of employee transition costs is "to mitigate potential negative impacts on utility personnel directly affected by electric industry restructuring . . . ." (Pub. Util. Code § 375(a).) Pub. Util. Code § 330 (u) reiterates this policy:

> "The transition to expanded customer choice, competitive markets, and performance based ratemaking as described in D.95-12-063, as modified by D.96-01-009, of the Public Utilities Commission, can produce hardships for employees who have dedicated their working lives to utility employment. It is preferable that any necessary reductions in the utility workforce directly caused by electrical restructuring, be accomplished through offers of voluntary severance, retraining, early retirement, outplacement, and related benefits. Whether workforce reductions are voluntary or involuntary, reasonable costs associated with these sorts of benefits should be included in the competition transition charge."

When more than one $50,000 payment has been made to an employee, ORA believes that the first $50,000 mitigated no "negative impacts" since the employee kept his job at the utility. Conversion of a legitimate employee protection program into a program of significant financial windfall for fortunate employees is not a reasonable administration of that program. ORA explains that one need look no further than the following situation at PG&E for evidence that the multiple $50,000 payments are unreasonable:

- Employee A: Worked at divested power plant, received final $50,000 payment, and was severed from the utility.
- Employee B: Worked at divested power plant, received $50,000 payment, was reassigned to another divested power plant with the wage protection guarantee of equal salary, received another $50,000 payment.

The record is persuasive that all payments made for the BUSD program including all $50,000 payments, were made in accordance with the terms and conditions of that program as approved in the Settlement Agreement among PG&E, ORA, and CUE. PG&E did not change the terms and conditions of the

BUSD program that were approved in the Settlement Agreement. PG&E incurred costs only for employees eligible to receive benefits under the specific terms of these programs; PG&E appropriately identified the costs to these programs; PG&E accurately recorded the costs associated with these programs to the TCBA; and PG&E's costs do not exceed the caps adopted in the Settlement Agreement.

The eight employees who received more than one $50,000 were eligible for the first $50,000 final payment they received under the BUSD program in connection with their displacement from the first divested power plant because: 1) they were regular employees whose positions at divested power plants were required by the Operations & Maintenance (O&M) agreement; 2) their positions were eliminated; and 3) they received displacement notices under the provisions of the collective bargaining agreement. Each of these eight employees were eligible for additional benefits under the BUSD program because, after being displaced from the first divested power plant: 1) they were placed as regular employees into positions at a second divested power plant that were required by the O&M agreement for that divested power plant; 2) their positions were eliminated; and 3) they received displacement notices under the provisions of the collective bargaining agreement. The receipt of more than one $50,000 payment as a result of working in more than one covered position at more than one divested plant fall squarely within the terms and conditions of the Settlement Agreement.

In our decision approving the Settlement Agreement and the BUSD, the position ORA now takes not only was considered and rejected, but also was opposed by ORA. In D.00-02-048, Aglet made the "negative impact" argument which ORA (as well as PG&E) opposed.

> "Aglet argues that employee benefit packages should be individually tailored to each employee and that PG&E's package of benefits is unreasonable because they do not differentiate among those employees who actually lose their jobs, those who are retained by new plant owners, those who retire, or those who transfer to a PG&E affiliate. ORA, on the other hand, contends that it would be inefficient to investigate the employment status of the individual employees and to determine whether the severance package was reasonable. ORA points out that such a requirement could create perverse incentives: if an employee knew that he or she were going to lose certain benefits if they obtained a new job after severance from PG&E, this would create an incentive for them not to take a job." (D.00-02-048 in A.98-09-003, p. 19.)

We reiterate what we said in D.00-02-048:

> "We have no wish to interfere in the collective bargaining process, nor do we find that employee retention bonuses are strictly eliminated from eligibility as employee-related transition costs. The Legislature clearly intended both that a stable workforce be retained in order to ensure reliability after divestiture and that the new competitive market be up and running in short order." (D.00-02-048, 2627.)

IV. SDG&E

SDG&E introduced evidence that its entries to its TCBA and its administration and costs of its QF, contracts and purchase power agreements with Public Service of New Mexico and Portland General Electric Company for the record period are reasonable and consistent with prior Commission decisions and that the continuation of SDG&E's competition transition charge (CTC) revenue requirement through 2003 ($115 million) is reasonable. ORA reviewed SDG&E's showing and recommends approval.

In compliance with D.99-05-051, SDG&E's End of the Rate Freeze proceeding, SDG&E filed Advice Letter 1174-E-A/1155-G-A, which included a revision to its TCBA tariff to reflect the recovery of ongoing transition costs in the post transition ratemaking period. The revised tariff, which became effective July 1, 1999, included the elimination of the residual calculation of available revenue to apply to transition costs and replaced it with an ongoing CTC rate component and a TCBA tariff to reflect ongoing transition revenues and the costs eligible for recovery after the rate freeze transition period.

In D.00-10-048, the Commission approved SDG&'s request for an annual CTC revenue requirement of $115 million effective January 1, 2001. SDG& proposes to maintain the annual CTC revenue requirement at $115 million through 2003 although the revenue requirement calculated based on the methodology adopted in D.00-10-048 would be significantly higher. The $115 million revenue requirement will be used to offset the large undercollection recorded in the Energy Rate Ceiling Revenue Shortfall Account. ORA concurs with SDG&E's proposal. We find it reasonable and adopt it.

V. Comments on Proposed Draft

The proposed decision of the Administrative Law Judge was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments were only filed by PG&E. It argues that the proposed decision erred 1) by deferring recovery of $34.8 million of hydro costs which the decision found were reasonably incurred and 2) by rejecting it's request for $580,000 in shareholder incentives. We find the comments unpersuasive. PG&E wants $580,000 for acting prudently. Prudence is the standard; it is expected; it does not warrant a reward. Merely because at a different time, under different circumstances, the Commission offered a reward is not sufficient reason to accede to PG&E's request.

We have deferred recovery of the $34.8 million to prevent the possibility of a double recovery by PG&E. PG&E asserts that the costs it incurred in connection with market valuation of the hydro facilities is "completely unrelated to any subsequent disposition of PG&E's hydroelectric generating facilities." (Comments, p.4.) In our opinion that statement is incorrect. Market valuation costs are necessarily related to the disposition of the facilities. If the facilities were sold today the market valuation costs would be deducted from the proceeds. (S*ee* D.97-12-107, 78 CPUC 2d 164 at 170.) We wish to assure that result should the hydro facilities be disposed of after December 31, 2005.

VI. Assignment of Proposed Decision

Geoffrey Brown is the Assigned Commisioner and ALJ Barnett is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. PG&E's record period entries to the TCBA were made based on PG&E's currently effective tariffs.

2. ORA filed a motion requesting bifurcation of certain issues in the 2001 ATCP such that the reasonableness of PG&E's procurement and generation activities would be considered in a separate phase. ORA's motion was granted.

3. The only active participants in Phase I of this ATCP were PG&E, ORA, and TURN.

4. ORA reviewed PG&E's showing, conducted discovery, and submitted its report on Phase I of PG&E's 2001 ATCP application that either approved or did not dispute all but four issues contained in PG&E's request.

5. In D.00-02-046, the 1999 GRC decision, the Commission determined that procurement costs were generation-related, rather than attributable to the distribution function. The Commission denied PG&E recovery of those costs

through its distribution rate, and instead provided PG&E with the opportunity to recover them in another forum. PG&E recorded those costs in the TCBA.

6. The Commission has approved inclusion of costs in the TCBA that do not meet the strict definition of "transition costs" in Pub. Util. Code §§ 367 and 840.

7. PG&E is not recovering the electric supply administration costs in its base rates or through any other balancing or memorandum account. These costs are recorded only in the TCBA.

8. PG&E's request reflects $6.2 million in direct costs of activities to perform the procurement function and, $3.4 million in indirect costs, less a prior period adjustment of $0.7 million. The $8.9 million of costs are reasonable and should be recorded in the TCBA.

9. Section 367(b) was added to the Pub. Util. Code in AB 1890 (Stats. 1996, Ch.854), while § 377 was revised in AB 6 of the First Extraordinary Session (AB1 6, Stat. 2001-02, Ch.2).

10. AB1 6 amends §§ 216, 330, and 377 by deleting references to "market valuation" as one of the factors affecting the Commission's continued regulation of utility retained generation related assets.

11. The purpose of AB 1890 was to expedite the transition to a competitive electric market and lower electricity prices. This regulatory scheme has been modified by ABX1 6 and ABX1 1.

12. In the absence of lower electricity prices, and in the face of a dysfunctional generation market, the Legislature prohibited the utilities from selling their generation plants and required the utilities to use the power from those plants to benefit ratepayers. The Commission has implemented these directives in D.01-01-061, D.01-10-067, D.02-04-016, and D.02-11-026 by applying cost-of-service ratemaking principles.

13. The confluence of AB1X 6, AB1X 1, and our explicit move to cost-of-service regulation results in utility retained generation assets continuing to be subject to our regulation, with the output dedicated to serving native load.

14. The costs for which PG&E has requested recovery are the costs PG&E incurred in connection with the AB 1890-imposed requirement to market value PG&E's hydroelectric generating facilities.

15. The activities for which these costs were incurred fall into four major categories: 1) preliminary asset assessment; 2) creation of data room; 3) participation in the Commission's market valuation proceedings and associated CEQA process; and 4) preliminary studies required by environmental and real property laws.

16. PG&E's hydroelectric system consists of 110 generating units as 68 powerhouses with a total generating capacity of 3,890 megawatts. It includes 99 reservoirs, 76 diversions, 174 dams, 184 miles of canals, 44 miles of flumes, 135 miles of tunnels, 19 miles of pipe, 5 miles of natural waterways, about 136,000 acres of land owned in fee, generation tie lines, administrative buildings, fleet, materials and supplies inventories, office equipment, and other miscellaneous instrumentation and monitoring support. The system includes 94 contracts for water rights and 163 statements of water diversion and use.

17. Given the size and physical location of PG&E's hydroelectric system, the level of professional expertise necessary to complete the necessary activities associated with preparing PG&E's hydroelectric generating facilities for market valuation and for participating in the Commission's regulatory proceedings addressing market valuation, PG&E's $34.8 million costs were reasonable, and should be held in a memorandum account to be allocated at the disposition of

the hydro facilities. Such disposition cannot occur earlier than January 1, 2006 and must be authorized by the Commission.

18. In order to bring additional energy to the marketplace during the record period, PG&E negotiated amendments to existing power purchase agreements with QFs facilities that could generate energy in addition to the amount delivered under the existing power purchase agreement.

19. PG&E paid for this incremental energy at negotiated rates that were specific to each QF. These rates took into consideration electric system needs and conditions and market pricing options.

20. The purchase price for power negotiated in each of these incremental agreements was lower than the price PG&E would have paid for the same power if it had purchased the power from the PX.

21. ORA agrees that it was reasonable for PG&E to enter into these incremental energy agreements and recommends that the Commission allow PG&E to recover the costs of these incremental energy agreements in the TCBA.

22. The costs and administration of PG&E's QF contracts and other power purchase agreements are reasonable and should be recorded in the TCBA.

23. PG&E should not be rewarded merely for acting prudently in renegotiating QF contracts and therefore $580,000 in proposed shareholder incentives should be disallowed.

24. The purpose of the BUSD program is to retain qualified workers required for plant operations through the period of the O&M agreement to ensure safe and reliable operation of these plants.

25. The incentive imbedded in the BUSD program to retain workers required for plant operations applies to the job positions (not specific individuals) at a

particular plant, whether or not that person had worked at another plant and had received a final payment of $50,000 upon displacement.

26. Nothing in the 1998 ATCP Settlement Agreement precludes multiple payments to employees who work at more than one impacted plant.

27. The employee transition costs PG&E incurred during the record period were consistent with the terms of the programs approved in the 1998 ATCP decision, and appropriately recorded in the TCBA during the record period.

28. No party other than ORA protested, commented, or submitted testimony addressing SDG&E's application.

Conclusions of Law

1. Except as set forth below, the entries for recovery through the TCBA in PG&E's application are reasonable and are approved.

2. The $8.9 million in costs associated with procurement of electricity from July 1, 2000, through June 30, 2001, are appropriately recorded in the TCBA, were reasonably incurred, and are approved for recovery through the TCBA.

3. PG&E administered all of its employee-related transition cost programs in accordance with the terms and conditions of those programs adopted in D.00-02-048. Those costs were reasonably incurred and are approved for recovery through the TCBA.

4. A reward for renegotiating QF contracts is denied.

5. The transaction costs of $34.8 million to prepare its hydro facilities for divestiture will be held in a memorandum account to be allocated at the disposition of the hydro facilities.

6. SDG&E's entries to its TCBA for September 1, 2000 through June 30, 2001 (record period) are reasonable.

7. SDG&E's QF contract administration and costs recorded in the TCBA during the record period are reasonable.

8. SDG&E's administration and costs of its purchase power agreements with Public Service of New Mexico and Portland General Electric Company recorded in the TCBA for the record period are reasonable.

9. The continuation of SDG&E's CTC revenue requirement of $115 million through 2003 is reasonable.

O R D E R

IT IS ORDERED that:

1. Except as set forth in this order, the revenues and costs recorded in the Transition Cost Balancing Account (TCBA) and TCBA-related memorandum accounts from July 1, 2000, through June 30, 2001 for Pacific Gas and Electric Company (PG&E), and from September 1, 2000 through June 30, 2001 for San Diego Gas & Electric (SDG&E), are approved.

2. PG&E is authorized to record the electric supply administration costs in the TCBA.

3. The transition costs of $34.8 million which PG&E incurred to prepare its hydro facilities for divestiture will be held in a memorandum account to be allocated at the disposition of the hydro facilities.

4. SDG&E's Competition Transition Charge (CTC) revenue requirement of $115 million through 2003 is adopted. Within 30 days of the effective date of this decision, SDG&E shall file and serve a compliance advice letter implementing the adopted CTC revenue requirement to be effective January 1, 2003.

5. This proceeding remains open to consider the reasonableness of PG&E's procurement practices.

This order is effective today.

Dated _____________________, at San Francisco, California.

APPENDIX A

************** SERVICE LIST **************
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APPENDIX A

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